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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning	Rulemaking 04-04-003 (Filed April 1, 2004)
Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities	Rulemaking 04-04-025 (Filed April 22, 2004)

OPENING COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE ALTERNATE DECISION OF COMMISSIONER GRUENEICH

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I. INTRODUCTION

At long last the Commission has moved to a nearly completed task in this proceeding. Cogeneration Qualifying Facilities (QFs) in California have remained in regulatory suspense for over four year with no public policy on utility obligations to offer firm contracts at reasonable pricing for these California resources. The interim period has been a nightmare for QF facilities. Commitments to sustaining existing capital investments, and certainly the ability to develop new CHP resources, have been seriously undermined. It is time to move to material solutions and effective implementation of a long term California combined heat and power (CHP) policy.

The Alternate Decision (Alternate) offers some hope of moving toward solutions. However, there remain critical issues for the Alternate to address now. The Alternate both gives and takes and endeavors to find a balance for a complex set of issues. All in all, the Alternate provides a framework for sustaining a successful California CHP program. There is a limited opportunity, both in the number of pages and the appropriate scope (legal or factual errors), to address material issues in comments under the Commission's rules. With these limitations in mind there are a few critical revisions and considerations the Commission must address. These issues are:

1. Eliminate unwarranted and prejudicial delay in establishing the standard offer (SO) by adopting a more rigorous implementation schedule, detailing a specific and comprehensive framework for SO terms and conditions, and assuring there is no "piecemeal" implementation of the Commission's final decision.

2. Establish a fixed heat rate energy pricing option for long term firm capacity resources at a reasonably discounted level (8,100 Btu/kWh) to allow these CHP projects to secure a long-term, predictable energy price stream.

3. Defend California's long term CHP policy decision against predictable utility appellate challenges asserting mistaken claims of federal pre-emption.

4. Clarify the definition of "small" QFs eligible for SO contracts.

5. Correct the factual and legal errors related to both future (for all utilities) and past (for SCE) as-available capacity pricing.

6. Specify the standards that the Commission will require to certify the viability of the MRTU "market" to reasonably establish utility avoided costs in the future.

The Cogeneration Association of California and the Energy Producers and Users Coalition (collectively, CAC/EPUC) necessarily reserve the legal and factual challenges raised in the proceeding with regard to issues that are not expressly addressed in these comments.[1] However, CAC/EPUC seek a rational and secure long term solution to the California CHP program. The Alternate forms a basis for attaining this objective if the Commission adopts the relatively limited considerations presented in these comments.

II. STANDARD OFFERS ARE ESSENTIAL BUT HAVE NO CHANCE OF SUCCESS ABSENT SPECIFIC COMMISSION DIRECTIVES

The Alternate appropriately recognizes the essential need for standard offer contracts in order to successfully sustain a stable and secure CHP program.[2] Yet there are several aspects of the Alternate's implementation of the SOs that are inconsistent, discriminatory and could promote gaming through piecemeal implementation. There are compelling reasons for the Commission to expeditiously establish, with unequivocal clarity and direction on specific terms and conditions, the SO contracts.

A. Delays In Establishing Standard Offers Should Be Unacceptable To The Commission Process And Delay Will Materially Prejudice Firm Capacity QFs With Terminating Contracts

For reasons that are not at all apparent, the Alternate calls for a workshop a full 60 days ***after*** the effective date of this decision. This workshop marks the first occasion that the utilities will be required to present a proposed SO. (AD at 137.) This long delay is unwarranted and prejudicial to firm capacity QFs who have long awaited a renewed contract or those who will soon lose their existing contracts.[3]

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1 For example, the lawfulness of confidentially requirements to preclude parties from securing utility system cost data to determine the recorded actual avoided cost of the utilities consistent with federal regulation (18 CFR § 292.302); or the erroneous conclusion that evidence has been presented to demonstrate the utilities' avoided cost, incremental loads, or the full costs of resources to meet incremental loads.

2 *"We do not want to see erosion of the utilities' QF supplies, therefore we expect that as old QF contracts expire, new or renewed QF contracts will replace them."* (AD at 126.) QFs eligible for SO contracts include those that *"are, or were, on contract extensions approved in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009."* (AD at 19.)

3 CAC/EPUC agree that a technical implementation workshop is appropriate to address price calculations and processes; the concern with the Alternate's proposed workshop is over the long delay and the failure to assure timely adoption of SO terms and conditions.

Utilities have repeatedly demonstrated opposition to SO contracts in this proceeding and will undoubtedly, if permitted, sustain their opposition through delay, gaming and less than productive contract "negotiations." QFs that have endeavored to engage in bilateral contract negotiations with utilities have experienced precisely these actions in "negotiations."[4]

Moreover, the Commission itself has recent, compelling, and far from optimal experiences in the development of standard offers under the same workshop model contemplated in the Alternate. The Renewable Portfolio Standard (RPS) proceeding also directed parties to a workshop to establish a standard offer based upon the EEI Master Agreement. The RPS proceeding faced a "highly expedited schedule" due to statutory deadlines for RPS implementation. (D.03-06-071 at 2.) It took parties and the Commission ***14 months*** to establish an EEI-form RPS standard offer contract.[5]

Any delay in establishing a SO contract in this proceeding will prejudice firm capacity QFs who have long waited for Commission action.[6] The situation faced by two individual CAC members is instructive. According to SCE, the existing long term firm capacity contracts for Sycamore Cogeneration Company (300 MW) and Watson Cogeneration Company (385 MW) expire on January 1, 2008.[7] These two projects have engaged SCE in unsuccessful bilateral negotiations for more than a year. Absent

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4 For example, KRCC's then existing 20 year firm capacity contract expired, and a restated contract was not finally negotiated and executed until four months later; the restated contract was not approved by the Commission until nine months after the expiration of the original firm contract. Significantly these "negotiations" have been subject to utility-imposed non-disclosure requirements that prevent a QF, but not the utility, from revealing any and all communications from the "negotiations" to the CPUC. This utility practice keeps the CPUC from critical information regarding the state of the California CHP contact development status – a material policy information vacuum for the Commission.

5 Must the untenable RPS process be repeated here? In the RPS, parties, using the EEI template, began with a workshop on March 11, 2003. Negotiations continued through the summer of 2003, but ultimately failed. The Energy Division then conducted a workshop in September 2003. Parties could not come to agreement on partial terms and conditions, much less an integrated standard offer contract. The unsuccessful workshops and negotiations were followed by legal briefing in November and December 2003, and again in March and April 2004. A diverse group of parties (CEERT, IEP, PG&E, SDG&E and TURN) offered a joint proposal based in part upon joint principles developed by SDG&E and TURN. Finally, in June 2004, fourteen months after the initial workshop, the Commission adopted standard terms and conditions for the RPS program. (D.04-06-014 at 2-3.)

6 The failure to have a QF contract also raises questions affecting the State's Resource Adequacy interests; the utilities might seek to eliminate counting any QF resource unless a contract is in place.

7 Another CAC member, Midway Sunset Cogeneration Company's (225 MW) existing firm capacity contract will terminate in the first quarter of 2009.

Commission action to establish a SO well before the end of the year, these projects will not secure the options provided by the Alternate. There is no reasonable bilateral contract available and they face the relatively imminent termination of their existing contracts.

There is no time for delay. The Commission needs to act immediately and decisively.

B. Adopt A Specific Standard Offer Contract Or Minimum, Specific Contract Principles To Encourage The Timely Adoption Of A Standard Offer Agreement

Reliance upon a "*simplified version of the Edison Electric Institute Master Agreement …[with] the contract features presented in Table 1 of this decision"* (AD Finding of Fact 38) is illusory and inadequate to frame a SO contract. More is needed.

The EEI Master Agreement is primarily a vehicle for merchant generator agreements with utilities and for trading power between marketers; it is not model for QF contracts. The contract features in Table 1 contain a few clear directives, *e.g.*, the treatment of credit terms and interconnection rights. But the Alternate reflects general contract directives from "30,000 feet" and nowhere near the specificity necessary to resolve particular SO contract provisions.[8]

Attached for the Commission's adoption as a template for immediate review and consideration is a fully developed form Standard Offer procedurally offered as a proposed Finding of Fact and Conclusion of Law.[9] The form SO follows the Commission's directives using as a starting point the EEI Agreement, and the guidance on specific terms from Table 1 (credit support, interconnection requirements and placeholders for final pricing provisions). Specific terms and conditions have been adopted from a contract that the Commission, the utilities, DRA and TURN have previously endorsed – the Mountainview agreement. This SO form contract offers a fully integrated and immediately available option to proceed with the implementation of the Commission's CHP program. It relies upon the very terms that the utilities are using to procure power from their own resources.

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[8] The Alternate also refers to Table 6 as listing "Power Contract Components," but the listed components are inapplicable to QF operations and seem merely types of electric market sales. The list does not provide contract term guidance to the parties. (AD at 77-78.)

[9] CAC/EPUC will also file a separate motion for adoption of this Standard Offer to allow the Commission alternative procedural avenues that may expedite the implementation of a form Standard Offer.

The Commission should establish a process for expeditious review and adoption of the attached SO form for QFs seeking firm capacity long term contracts. The process should allow parties to challenge any specific terms inconsistent with the Commission's prospective program, but also allow QF parties the ability to timely secure reasonable contracts. Since every final contract for procurement is subject to CPUC approval, this process would afford all parties procedural protections necessary while securing long delayed contract options.

Moreover, the CPUC at the very least should provide specific guidance to parties endeavoring to frame the SO. The Alternate has taken a few limited steps down this path, *i.e.*, credit terms and interconnection issues. But greater specificity is essential. The Commission should promptly adopt the following resolution of critical contract issues:

- Reliance on specific terms and conditions from the Mountainview or Contra Costa 8 contracts as a default.

- Pass through of GHG taxes or costs – GHG costs are "social costs" to be borne by all consumers. Utility projects and RFOs have explicit provisions to provide for the pass through of such costs; identical, parallel provisions should be required for QF GHG taxes or costs, once those costs are established and imposed.

- Performance obligations associated with 90% and 95% delivery – the relevant delivery period for such performance should be specifically designated as the seasonal off-peak and on peak periods, respectively. These performance obligations should sustain the existing flexibility and delivery options for QFs over a relevant seasonal period and not for shorter intervals of delivery obligations.

- CAISO obligations – continue the state jurisdictional reliance on utility Rule 21 point of interconnection and delivery for all QFs, regardless of size, with obligations for interface with the CAISO retained by the utility for QF delivered capacity and energy.

Time remains of the essence in developing and implementing the Standard Offer. After almost five years for the development of a long term QF contract policy, additional delay is unreasonable and prejudicial. The Commission must provide specific rulings related to SO terms and conditions, and it needs to do so now.

C. Piecemeal Implementation Of The Commission's Decision Will Promote Gaming And Discrimination Against Firm Capacity Suppliers Under "Bridge" SO1 Agreements

Over the last five years terminating firm capacity QFs were left with limited future contract alternatives. Commission decisions[10] offered "interim" relief by providing "bridge" as-available capacity SO1 agreements from utilities (who opposed these contracts). These as-available contracts provided no realistic economic option in the SCE service territory in light of the non-cost reflective (and rigorously protested) $4.93/kW-year capacity price.[11] In the PG&E and SDG&E service territories the capacity price was at least reflective of avoided cost for as-available capacity. But for all these "bridge" SO1 agreements, the pricing provisions call for automatic adjustment upon the issuance of revised pricing from the CPUC.

The Alternate is unclear regarding the implementation of the Commission's decision. It would appear that no implementation can take place until after issues are resolved and adopted in the post decision workshop. However, absent clear direction, the utilities may seek to impose "automatic" adjustments in the "bridge" SO1 contracts. This would essentially compound the prejudice to firm capacity QF suppliers who are subject to an inappropriate as-available contract and capacity price. Not only would the firm QF supplier be subject to an as-available contract, but the price terms would potentially call for a dramatic reduction in the PG&E and SDG&E service territories.

The concern that the Commission should address is over piecemeal implementation of this order. The decision should require that all of the features of the order, including a reasonable transition period of at least 30 days, be available before any portion of the order is implemented. Failure to adopt this requirement would provide distorted incentives to utility parties, and support gaming in the development of the SO contract.

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10 Decision 05-12-009 continued the interim relief provided in D.04-01-050 for QFs with expired or expiring contracts from January 1, 2006 until the Commission issues a final decision in the combined two dockets, R.04-04-003 and R.04-04-025. (D.05-12-009 at 1.) The interim or "bridge" relief will terminate upon issuance of the Commission's final decision in the consolidated dockets while QFs will not be able to see even a first draft of a contract until potentially sixty days after the interim relief is terminated.

11 *See*, CAC/EPUC's Motion for Immediate Action Establishing an Updated, Posted As-Available Capacity Payment for Southern California Edison Company filed May 27, 2005; and Emergency Motion of the Kern River Cogeneration Company for Immediate Relief and Action on Pending Motion, filed July 18, 2005.

If the prices from the Alternate were immediately implemented, existing as-available contracts, including the "bridge" contracts, would experience an immediate and dramatic reduction in capacity and energy payments. For QFs who would seek to elect a firm capacity contract, the SO would potentially be a long way off in terms of availability. The utilities would have an incentive to delay and game the process for the establishment of the long term SO contract while imposing ever lower prices on existing firm supply resources. Moreover, the utilities would have an incentive to delay the SO until after the implementation of the CAISO's MRTU in order to challenge the Commission's long term QF contract policy before contracts are offered.

The Commission should preclude any efforts to allow piecemeal implementation of its long term QF contract policy. All components should be available before any single component is implemented. Alternatively, the Commission could simply allow any existing firm capacity contract supplier to reinstitute their former, or retain their existing, firm supply contract incorporating the newly adopted LRAC pricing until a Standard Offer is adopted and available.

D. Conclusion Regarding Standard Offer Development Requirements

Specific Commission guidance is required on terms and conditions for adoption of a SO firm contract. Timing is critical and any additional delay in the implementation of the Commission's QF contract policy must not be accepted. Absent immediate and clear Commission action, QFs face discriminatory, prejudicial and unreasonable practices that hobble the long term prospective QF program.

III. ADOPT A FIXED HEAT RATE PRICING OPTION FOR LONG RUN AVOIDED COST ENERGY PRICING

State law and expressions of state policy call for the long term integration of CHP resources for California's generation supply. (AD at 6, Energy Action Plan II.) For long run avoided cost (LRAC) suppliers, stability and certainty in power payments provide a basis for investing in and sustaining long term CHP. The Alternate notes, but apparently fails to appreciate, a proposed option for LRAC energy pricing, and encourages proposals for fixed pricing from some parties. (AD at 128-129.)

The Alternate indicates that the Commission is not in a position to adopt fixed price options at this time. Yet the Commission has adopted a fixed heat rate for energy pricing under the MPR model, and there is a basis in this proceeding for setting such an option.

The CAC/EPUC proposal is a fixed heat rate option for LRAC energy pricing (as distinguished from SRAC energy pricing). The option would allow long term firm capacity QFs to elect to fix the heat rate component in the calculation of their LRAC energy price. The fixed heat rate would be at 8,100 Btu/kWh[12] for the term of the LRAC contract; a material discount to the projected 8,598 Btu/kWh SRAC heat rate. The proposal is contingent on other LRAC pricing components (capacity and the O&M adder) remaining as established in the Alternate.

As reflected in the following table, this option, if applied to just three CAC projects, would have a significant (in excess of $25 million) reduction in energy costs for consumers.

Fixed Heat Rate Savings Calculation		
Line	**Description**	**Assumptions and Calculations**
1	Assumed Natural Gas Price (Annual Average)	$7.50/MMBtu
2	Energy for 900 MW* at 90% Capacity Factor	7,095,600 MWh
3	Alternative PD Illustrative MIF Heat Rate	8,598 Btu/kWh
4	Proposed LRAC Fixed Heat Rate	<u>8,100 Btu/kWh</u>
5	Heat Rate Reduction	498 Btu/kWh
	Annual Reduced Energy Payment at Fixed Heat Rate	
6	Reduction [Line 2 x ((Line 1 x Line 5) ÷ 1000))]	$26,502,066.00
* Watson, Sycamore and MSCC @ 900 MW		

The Commission has adopted other forms of fixed and predictable capacity and energy pricing. This proposal is not a novel concept or one that the Commission should be reticent to adopt as an option in light of the basis for the 8,100 Btu/kWh figure. Moreover, this option will allow QFs who wish to secure their future against an uncertain MRTU

12 The 8,100 Btu/KWh heat rate is reflective of the MIF derived heat rate from the SP-15 "market" price. Accordingly it is a heat rate that the Alternate recognizes is too low to be reflective of the utilities' avoided cost.

market the opportunity to do so. This pricing stability will encourage long term reliable supplies at a stable cost.

The Alternate should be revised to adopt this option for a fixed heat rate in the establishment of the LRAC energy rate.

IV. THE COMMISSION SHOULD ANTICIPATE UTILITY CHALLENGES AND ESTABLISH FIRM APPELLATE PROTECTIONS TO SUSTAIN A LONG TERM POLICY FOR CALIFORNIA CHP RESOURCES

The Commission should anticipate and establish firm grounds to repel appellate challenges from the utilities to the long term QF contract policy. The final decision should be soundly based upon State law in addition to federal provisions. Moreover, the Commission should note that the utilities have not challenged the State's RPS program – a program for renewable QFs. That action should be noted in the decision as an implicit waiver of any federal preemption claim against CHP QFs, since the CPUC may not discriminate against QFs in the administration of a State program.

Issues regarding federal preemption of state action are often complex and sometimes less than clear.[13] But the Commission has substantial grounds to preserve its policy decision in the face of preemption claims. These grounds are addressed in the following section.

A. The CPUC Has Authority Under EPAct 2005 To Impose Mandatory CHP Purchase Obligations On State Jurisdictional Utilities

The Energy Policy Act of 2005 (EPAct 2005) addressed certain rights of future QF resources. But it also explicitly protected QF obligations arising from pending state PURPA implementation proceedings, *i.e.*, the CPUC's rulemaking in this docket. Section 210(m)(6) provides that PURPA rights under existing "contracts or obligations" and those that are "pending approval" are not subject to change:

> *NO EFFECT ON EXISTING RIGHTS AND REMEDIES.— Nothing in this subpart affects the rights or remedies of any party under any <u>contract or obligation</u>, in effect <u>or pending approval</u> before the appropriate State regulatory authority or non-regulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or*

[13] Indeed, in this proceeding a party has erroneously suggested that the only State basis for setting wholesale rates for larger QFs will be eliminated under EPAct 2005 implementation. (AD 19-20, 27.) This mistaken and inaccurate representation should be eliminated from the Commission's order.

to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).[14]

An "obligation" within the scope of Section 210(m)(6) is a legally enforceable obligation that arises from a pending state PURPA implementation proceeding:

Section 210(m)(6) of PURPA protects the rights and remedies under a contract or obligation in effect or pending approval before a state regulatory authority. In the Final Rule, the Commission interpreted the term "obligation" as a "legally enforceable obligation," which is established through a state's implementation of PURPA. The Commission stated that a QF that had initiated, prior to date of enactment of section 210(m) (i.e., August 8, 2005), a state PURPA proceeding that may result in a contract or legally enforceable obligation would be considered to have triggered an "obligation" with an electric utility regarding section 210(m)(6).[15]

An obligation is "pending approval," as required by Section 210(m)(6), if it was being pursued at the time of EPAct 2005's enactment:

the phrase "or pending approval" [is] quite significant, as it ensures that contracts or obligations that had not yet been entered into but <u>were being pursued in the context of the state commission proceedings</u> that were pending on the date of enactment of EPAct 2005 will fall within the savings clause.[16]

Section 210(m)(6) and FERC's order demonstrate that obligations which arise from the CPUC's avoided cost proceeding will be grandfathered and protected from utility challenge. First, both underlying proceedings are related to the State's implementation of PURPA and arise prior to EPAct 2005's implementation:

- Rulemaking 04-04-025, instigated on April 22, 2004, is directed in part to updating the avoided cost formula including that applicable to purchases of power from QFs pursuant to PURPA.[17]
- Rulemaking 04-04-003, which commenced on April 1, 2004, is directed in part to developing a long-term policy to address expiring QF contracts.[18]

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[14] Order 688-A, at ¶ 136 (emphasis added).

[15] Order 688, at ¶ 212; Order 688-A, at ¶¶ 128 and 136.

[16] Order 688-A at ¶ 139 (emphasis in the original).

[17] Order to Institute Rulemaking for R.04-04-025, at 12-14.

Second, the obligations were "pending approval" because, beginning in April 2004, QF obligations "*were being pursued in the context of a state commission proceeding*."[19] The CPUC's avoided cost and long term QF contract policy proceeding satisfies the criteria of Section 210(m)(6), and pricing or contract terms pursuant to the CPUC decision will create legally enforceable obligations under Section 210(m)(6).[20] As a result, CPUC-imposed mandatory purchase obligations not only would be allowed under EPAct 2005, they would also be protected from challenge by utilities.

B. The CPUC Has Plenary Authority To Exercise Traditional State-Based Procurement And Rate Setting Authority Over Utilities To Encourage Cogeneration

In addition to the deference afforded to state regulatory authorities under EPAct 2005, state law sustains the plenary authority of the CPUC to direct the procurement activities of utilities, and specifically of CHP resources. The regulation of state utilities is within the traditional police powers of the state.[21] As such, it is accorded much deference, especially in the context of the supremacy clause:

> *Where . . . the field that Congress is said to have pre-empted has been traditionally occupied by the States, "we start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress."*[22]

Regulation of utilities is *"one of the most important of the functions traditionally associated with the police power of the States*." [23] PURPA's legislative history and the changes resulting from EPAct 2005 also indicate that Congress intended to leave room for

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18 Order to Institute Rulemaking for R.04-04-003, at 18.

19 Order 688-A at ¶ 142.

20 FERC Order 688-A clarifies that if a utility petitions FERC to have its mandatory purchase obligation terminated, FERC will first determine, using state law, whether a contract or obligation exists. Order 688-A, at ¶ 137

21 *See Arkansas Elec. Coop. v. Arkansas Public Comm'n*, 461 U.S. 375, 387 (1983); *In re Consolidated Edison Company of New York, Inc.*, 63 N.Y.2d 424, 434 (Ny.App.Ct. 1984).

22 *Hillsborough County v. Automated Medical Laboratories, Inc.*, 471 U.S. 707, 715. *See also New York v. FERC*, 535 U.S. 1, 17-18 (2002); *Maine v. Taylor*, 477 U.S. 131, at 138 (1986).

23 *Arkansas Elec. Coop. v. Arkansas Public Comm'n*, 461 U.S. 375, 377 (1983).

state regulation of QFs.[24] Under these facts and findings a presumption against federal preemption of state action related to CHP obligations established by the CPUC will apply.

Finally, state law and regulation compel the CPUC to take actions to encourage the retention of existing and the development of new CHP resources. This California law and policy should be explicitly referenced in the final decision as an independent basis for the prospective QF program:

- California's Warren-Alquist Act explicitly commits the State to the promotion and development of cogeneration;
- California Public Utilities Code Section 372(a) provides that it is policy of California to encourage cogeneration;
- California Public Utilities Code Section 372(f) encourages the development, installation and interconnection of cogeneration facilities; and
- The Joint Agency Energy Action Plan II lists cogeneration as one of its preferred energy sources.[25]

The CPUC also has broad authority to "*supervise and regulate every public utility in the State and may* <u>*do all things*</u>*, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction.*"[26] Given this broad authority and the State law existing to encourage cogeneration, the CPUC has the authority to direct utility procurement and pricing in a manner that would encourage cogeneration.

V. THE STANDARD OFFER ELIGIBILITY FOR NEW QFs OFFERING SMALL BLOCKS OF POWER NEEDS CLARIFICATION

The Alternate expressly adopts TURN's position extending SO eligibility to new "small" QFs, "*as modified by CAC/EPUC*." (AD, at 2, 3, 120, 144.) The CAC/EPUC

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[24] PURPA's legislative history and FERC's implementation of PURPA in Order 69 evidence the intent to leave room for state regulation of QFs. *See In re Consolidated Edison Co. of New York, Inc*., 63 N.Y.2d 424, 436 n.7 (Ny.App.Ct. 1984); FERC Order 69. The modifications to PURPA resulting from EPAct 2005 provide further support that room for state regulation exists because it states only that a utility will not be required to enter into a new contract "*under this section.*" 16 U.S.C. §824a-3(m). This necessarily means "other sections" including the existing delegation from FERC to the states to set avoided cost prices provides legal support for the CPUC action in this proceeding.

[25] Energy Action Plan II, at 2, 7, 8.

[26] P.U. Code §701.

modification was that "small" be defined as *either* being under 25 MW of capacity *or* delivering the annual energy delivery equivalent of 164,250 MWh (25 MW x 8760 x 0.75). In gauging the risk of oversubscription, the relevant criteria is the actual amount of power delivered, not nameplate capacity. The rationale for extending SO eligibility to these new QFs is that such small blocks of power do not risk oversubscription of utility portfolios. The Alternate should clarify the new "small" QF proposal to state that QFs that are either under 25 MW or offer the annual energy delivery equivalent of 164,250 MWh are eligible for SO contracts.[27] The current language in the Alternate regarding this definition is somewhat awkward and could be subject to misinterpretation and debate. Accordingly clarification of the criteria for defining "small" QFs is warranted.

VI. THE ADOPTION OF ANCILLARY SERVICES REDUCTION TO THE AS-AVAILABLE CAPACITY PRICE IS FACTUALLY AND LEGALLY IN ERROR

The Alternate erroneously permits the full value of as-available capacity, \$64.13/kW-year, to be reduced by \$14.82/kW-year based on supposed market sales of ancillary services. There is an inherent flaw in the logic to adopt this deduction.

The proxy resource, a CT, is paid a reservation fee, *e.g.*, \$64.13/kW-year, for its "availability" during every hour of the year whether the resource is dispatched or not. This means in an hour when the CT is in fact dispatched, it has no opportunity to seek the alternative ancillary services payment of \$14.82/kW-year. It is only in an hour when the CT is not dispatched that it can secure the ancillary service price. In the hour when the CT is not dispatched it would still receive the reservation fee payment of \$64.13/kW-year.

In contrast, a QF does not receive a reservation fee. The QF capacity price payment is not a reservation fee; the QF is only paid for capacity if it is in fact operating and delivering capacity and associated energy. This means the QF receives zero payment in any hour that it does not deliver. If the QF is not operating and available it cannot secure any capacity payment, or any alternative payment from the ancillary services market.

Under the Alternate, a QF could operate and deliver virtually every single hour of the year and still not receive the full capacity price; the payment would nevertheless be

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[27] For example, a QF with capacity of 49 MW would be defined as a small QF if the annual delivery of energy from the facility was limited to 164,250 MWh.

subject to the ancillary services discount. The flaw in the Alternate is the presumption that the QF is paid regardless of its delivery like the CT; it is not. The ancillary services deduction should not be applied to the QF as-available capacity payment. Alternatively the deduction could be applied, but only if the QF was entitled to be paid the same reservation fee as the CT whether the QF was delivering power or not. This alternative is not the right answer; but the elimination of the ancillary services deduction to the QF as-available capacity price is the right answer.

VII. THE ALTERNATE IMPROPERLY IGNORES CAC/EPUC'S MULTIPLE REQUESTS FOR UPDATES TO THE UNLAWFUL SCE AS-AVAILABLE CAPACITY PRICE

The Alternate, in describing as-available capacity prices, refers to an all parties' settlement implementing Section 390. The Alternate states that the SCE as-available capacity payment of $4.93/kW-year "*was uncontested*." (AD at 75-76.) While uncontested <u>in 1997</u>, CAC/EPUC have strenuously objected to the unreasonably low SCE as-available capacity price and urged timely Commission action.[28] This was particularly true as the CPUC refused to retain the features of the Section 390 settlement.

Multiple motions and pleadings specifically requested expeditious relief from SCE's outdated as-available capacity price.[29] In its final decision, the Commission must address and remedy the record objections to the flawed SCE as-available capacity pricing. A retroactive upward price adjustment for SCE as-available is warranted.

VIII. STANDARDS FOR ADOPTION OF ALTERNATIVE PRICING FOR SRAC OR LRAC ENERGY PRICING

Energy prices are subject to modification (through an adjustment to the MIF) after MRTU implementation. The Energy Division is directed to review the MIF six months after

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28 CAC/EPUC consistently raised the need to address QF issues in a timely manner ***for over <u>four</u> years***, both here and in R.01-10-024. In this proceeding, CAC/EPUC re-iterated the need to address avoided cost issues expeditiously through its December 2, 2004 Motion for Interim Relief. *See also, e.g.,* Comments of CAC and EPUC on Revised Alternate Proposed Decision of Commissioner Lynch, dated January 20, 2004, in R.01-10-024; *see e.g.,* Direct Testimony of CAC and EPUC, dated June 23, 2003, in R.01-10-024. This is but a partial listing of the repeated claims for immediate revision, and for retroactive price adjustment, raised by CAC and EPUC in this proceeding over the years.

29 "*CAC/EPUC respectfully request that the Commission immediately establish an updated as-available capacity payment for Edison.*" CAC/EPUC Motion for Immediate Action Establishing An Updated, Posted As Available Capacity Payment for Southern California Edison Company, filed May 27, 2005, at 2; *see also* Emergency Motion of Kern River Cogeneration Company for Immediate Relief and Action on Pending Motion, filed July 19, 2005.

the operational date of MRTU. (AD at 67.) However there is virtually no Commission guidance given to the Energy Division or parties as to the standards for evaluation of the MRTU "market" that should be employed. The Commission and all parties would be well served to know these standards now. This knowledge will support business decisions regarding the future viability of pricing for QFs, and help encourage CHP resources for California. At a minimum the evaluation standards should include:

- The availability of reasonable price and delivery terms under varying operational, supply and demand conditions – evaluated over time, times of day, seasons, and varying operating conditions, including during periods of shortage.

- Market prices that reflect the full incremental costs in utility service territories to serve incremental loads under economic dispatch conditions, and prices that will allow the recovery of variable and fixed cost as well as a return on investment for generation resources.

- Market prices that sustain reliable long term delivery of power to the grid by non-dispatchable cogeneration QF operations. The market must provide a real and workable substitute for existing PURPA must-take and full avoided cost pricing obligations. The test of any such market is the maintenance of comparable procurement and market share for existing and new cogeneration facilities.

- An absence of market power in location or time in a utility footprint from any participant, especially the utility itself.

- The non-existence of "exit fees" or other economic disincentives for loads to seek alternative sources of generation supply than from the interconnected utility.

IX. CONCLUSION

For all of the forgoing reasons the Alternate should be modified to address factual and legal issues as presented in these comments.

Respectfully submitted,

Michael Alcantar	Evelyn Kahl
Rod Aoki	Nora Sheriff
Counsel to the	Counsel to the
Cogeneration Association of California	Energy Producers and Users Coalition

September 10, 2007

APPENDIX A
PROPOSED MODIFICATIONS
(Additions, ~~deletions~~)

Page 2

Specifically, we adopt:

- **The Market Index Formula (MIF),** which is an updated short-run avoided cost (SRAC) formula for pricing SRAC energy. The MIF is based on the formulistic method adopted in Decision (D.) 01-03-067 ~~Modified Transition Formula~~ but contains both a market-based heat rate component, and an administratively determined heat rate component to calculate the incremental energy rate (IER);

* * *

  - Longer term, As-Available Power Contract for new QFs ~~under 25 MW~~ that consume at least 25% of the power internally and sell 100% of the surplus to the utilities and either are under 25 MW or offer the equivalent annual energy deliveries of 164,250 MWh without an oversubscription limitation.

Page 3

- **Prospective QF Program Contract Provisions**

  - SRAC Energy Payments: Market Index Formula (MIF). Existing QF contracts with energy pricing provisions specifically stating that the Commission determined ~~providing~~ SRAC is the basis for energy payment will also be priced pursuant to the MIF.

  - Payments for As-Available Capacity: Based on the full fixed cost of a Combustion Turbine (CT) and the economic carrying charge as proposed by The Utility Reform Network (TURN), less the ~~estimated value of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E) and~~ capacity value that is recovered in market energy prices as proposed by TURN and SDG&E.

* * *

An Entry Procedure for New QFs. New QFs may seek either of the first two contracts as follows:

  - New, as available QFs that (1) either are 25 MW or smaller~~,~~ or offer the equivalent ~~expressed as an~~ annual ~~limitation~~ energy deliveries of 164,250

MWh (25 MW x 8760 x 0.75) or less, (2) that consume at least 25% of their power internally, and (3) sell all of their additional output to the utility are eligible for a …

Page 4

After:

- The new QF should make its request for a new QF contract to the IOU in writing. The new QF may send a copy of its request to Commission's Executive Director, Energy Division Director, and the Division of Ratepayer Advocates (DRA).

Add:

- Where the new QF sells all of its exported power to the interconnected utility its interconnection shall be governed by state jurisdictional utility Rule 21.

1.1 Recent Developments and Scope of this Order

Two recent developments limit the effect of this order ~~on energy prices and capacity prices over the next five years~~ because (1) a large number of QFs have entered into contractually based energy pricing agreements, and (2) many existing QFs are on contractually based capacity pricing. In addition, we anticipate that the Market Redesign and Technology Update (MRTU) will be operational within the next 12 to 18 months and may ~~will~~ provide a robustly traded day-ahead market that accurately establishes a market price based on the full short-run avoided energy costs of the state's utilities.

Page 8

However, we are persuaded that there are currently few options to utility purchases, particularly for ~~Small~~ QFs offering small blocks of as-available power, ~~whose size~~ which prevents them from participation in the CAISO markets. These QF should continue to have available standard offers, albeit at market-based prices.

For these reasons, we adopt flexible market-based contract options in addition to the competitive solicitation and bilateral contracting options already available to QFs. First, QFs who choose only to provide non-firm, as-available power will have access to a one- to five-year as-available contract with energy prices based on the forward-based MIF formula and posted as-available capacity payments based on the full cost of a combustion turbine less the ~~estimated value of Ancillary Services and the~~ capacity value that is recovered in market energy prices.

Page 8-9

Second, we will make available a one-to-ten-year contract for firm unit-contingent power, with energy prices based on the MIF formula ~~market price referent (MPR) heat rate value in Resolution E-4049~~, and capacity payments based on the MPR capacity cost in Resolution E-4049, less the value of energy-related capital costs. This longer-term contract option is intended to provide sufficient contract and pricing certainty to allow QFs to make decisions on capital expenditures for facilities and upgrades. In addition, QFs under 25 MW or offering annual energy deliveries of 164,250 MWh or less are eligible for ~~a~~ standard offer contracts.

Page 10

We also continue to require the utilities to make available CAISO scheduling services to all QFs. ~~QFs whose size prevents them from participation in the CAISO markets should not have to establish scheduling operations staff to interact with the CAISO.~~

Page 15

PURPA, and related FERC regulations, delegate the implementation of the pricing provisions to the states. Additionally, California law and policy provide an independent basis for the prospective QF program. Specifically, California's Warren-Alquist Act explicitly commits the State to the promotion and development of cogeneration; California Public Utilities Code Section 372(a) provides that it is policy of California to encourage cogeneration; California Public Utilities Code Section 372(f) encourages the development, installation and interconnection of cogeneration facilities; and the State’s Energy Action Plan II lists cogeneration as one of its preferred energy sources.

Page 19-20

In response to the Obligation NOPR, the IOUs argued that the potential end of the PURPA mandatory purchase obligation under EPAct 2005 should cause the Commission to be very cautious and limit any new contracts to very short duration (e.g., one year). In contrast, ~~the QF parties suggest that the Commission should do the opposite, noting that the only jurisdiction that the Commission has to set wholesale power prices is the jurisdiction that the Commission derives from PURPA. As such, the~~ CCC argues that the Commission should view the continuing purchase obligation as a “window of opportunity” within which to secure the benefits of cogeneration by making long-term contracts with avoided cost pricing available to cogenerators whose contracts expire and to new cogenerators.

Pages 21-22

After footnote 45 insert the following:

Order 688 also expressly recognized that Section 210(m)(6) of PURPA protects the rights and remedies under a contract or obligation in effect or pending approval before a state regulatory authority. In that Order, FERC interpreted the term “obligation” as a “legally enforceable obligation,” which is established through a state’s implementation of PURPA. FERC noted that as long as the PURPA process was initiated prior to the date of enactment of section 210(m) (i.e., August 8, 2005), a state PURPA proceeding that may result in a contract or legally enforceable obligation would be considered to have triggered an “obligation” with an electric utility regarding section 210(m)(6). FERC further found the phrase “or pending approval” to be quite significant, as it “ensures that contracts or obligations that had not yet been entered into but were being pursued in the context of state commission proceedings that were pending on the date of enactment of EPAct 2005 will fall within savings clause.” In making these determinations, FERC specifically concluded that it is the state regulatory authority that determines whether and when a legally enforceable obligation is created, and the procedures for obtaining approval of such an obligation.

The Commission initiated these consolidated proceedings in response to requests from the QF community for Commission assistance in development of a long term policy for expiring QFs, the availability of contractual options for those QFs, and pricing under those contracts. The Commission initiated these consolidated proceedings in April of 2004, prior to the date of enactment of Section 210(m) (i.e., August 8, 2005). Today's decision addresses the QF Program as it exists today~~, in accordance with the modified mandatory purchase obligation~~. Therefore, our policy determinations must ensure that QFs continue to have opportunities to provide power to the utilities under terms and conditions that offer mutual benefit to utilities, consumers and QFs. These proceedings will result in a contract or legally enforceable obligation with an electric utility as of the date of the Commission's final decision in these consolidated proceedings.

Page 40

CAC/EPUC and IEP are opposed to pricing SRAC energy at market levels and support a continued reliance on the ~~a largely~~ administratively determined formula that has been demonstrated to appropriately reflect what they believe are the utilities' short-run avoided energy costs. ~~requires periodic adjustment via protracted litigation.~~ They argue that the Commission should reject the utilities' SRAC energy pricing proposals and continue to set monthly SRAC energy prices using the Section 390(b) formula. They advocate changes to the capacity payments, as well as a change to SCE's factor, but no change to the SRAC energy pricing formula for SDG&E and PG&E. Their primary objections are summarized briefly below.

Page 54-55

Existing resources in PG&E's portfolio (i.e., utility retained generation, CDWR, and those contractual obligations which allow economic dispatch) are regularly compared to the market price, with power being either bought or sold at that price. Regardless of the resource stack, according to PG&E, the utility's avoided cost for a given hour becomes the market price. The market price that PG&E contends that it uses to determine what resources are dispatched in northern California is the NP15 price. If the dispatch decision is made day-ahead, then the price is the day-ahead NP15 price. If the dispatch decision is made hour-ahead, then the price is the hour-ahead NP15 price. PG&E states that its ~~'s~~ traders are active in the market and are keenly aware of current prices at which sellers are offering, buyers are bidding and the price at which the most recent transaction was executed. Price discovery is available through voice brokers, electronic trading platforms, such as the ICE, and direct contact with trading counterparties. (*Id.*, p. 3-10.)

Page 69

We concur with the ~~this~~ approach of relying on the Market Price Referent CCGT variable O&M component and adopt it for use in the SRAC energy formulae for the three utilities.

Page 76

Although the SCE value of $4.93/kW-year was much lower than that for the other utilities, it was uncontested and memorialized in a Joint Recommendation signed by CCC, CAC, DRA, IEP, Watson Cogeneration Company (WCC), and SCE, and the value of $4.93/kW-year had been adopted in each of SCE's last five ECAC proceedings, 1992-1996 (D.96-12-051, pp. 4-5). Over the past several years, however, CAC and EPUC have asserted that the low SCE value is flawed, no longer represents SCE's need for added capacity and requires updating.

Page 90

Today, we adopt two contract options for expiring or expired QF contracts and new QFs – Our Prospective QF Program. The first option is a one- to five-year as-available power contract. The second is a one- to ten-year firm, unit-contingent power contract. Payments for as-available capacity will be based on the fixed cost of a Combustion Turbine (CT) as proposed by The Utility Reform Network (TURN), less the ~~estimated value of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E) and~~ capacity value that is recovered in market prices, as proposed by TURN and SDG&E. Payments for firm, unit-contingent capacity will be based on the market price ….

Pages 93-94

Once a full CT capacity value is determined, adjustments to that value may ~~should~~ be considered. ~~For example, we agree that the value of additional (ancillary services) revenue streams associated with the physical ownership of an actual CT should be accounted for in our estimate of capacity value.~~ In its rebuttal testimony, CCC recommended the use of the full cost of a CT as the avoided value of as-delivered capacity, but also acknowledged that an adjustment to as-delivered capacity prices would be warranted given certain substantial evidence. (Exhibit 103, pp. 59-60.) CCC explored TURN's evaluation of the potential for such an adjustment based on an assessment of energy profits where an adjustment hinged on an accurate estimate of the number of hours of annual CT operation.

~~SDG&E recommends that:~~

> ~~the value of the CT in the ancillary service market would be deducted from proposed annual avoided capacity cost. As the name "as-available" implies, the as-available capacity of a QF does not have the same characteristics as a CT that can be dispatched as needed. If the utility owned a CT, it could capture added value by offering the unit in the CAISO ancillary services market as non-spinning reserve, while the utility cannot obtain that value from an as-available QF. It is estimated that this ancillary services value over June, 2003 - May, 2005 was $14.78/kW-year. The full avoided generation cost is projected to be $83.75 per kW-year less the ancillary value of $14.82 per kW-year, so the proposed value for full as-available capacity is $68.93/kW-year in 2006. (Exhibit 85, p. 15.)~~

~~SDG&E proposes a methodology for estimating its recommended ancillary services value adjustment of $14.82 per kW-year, to account for revenue received from the CAISO for the provision of non-spinning reserves. The CAISO defines this product as follows:~~

> ~~Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions.~~

~~SDG&E assumed a 5% maintenance outage rate (438 hours/year), and that the CT would actually be operating (e.g., to serve native load) for 634 hours/year or about 7.2% of the year. During the remainder of the year (8,760 – 438 - 634 = 7,688 hours), the CT would be available to the CAISO to provide non-spin ancillary services. SDG&E obtained~~

~~monthly non-spin prices from the CAISO for the period of June 2003 through May 2005 with a simple average of $1.93 per MW. Thus, the capacity value for non-spin reserves is estimated to equal 7,688 hours times $1.93 per MW = $14,815/MW or $14.82/kW-year.~~

Page 95

We agree with TURN, SCE, and SDG&E on this issue. The avoided CT annual cost should be based on an economic carrying charge rate, escalated for inflation over the life of the contract. Using a levelized nominal dollar value to compute the CT annual cost would ~~overstate the avoided capacity cost as well as~~ present additional cost and risk for utilities and ratepayers. A primary concern is that the use of a levelized nominal value would require higher capacity payments in early years, exposing the utilities and their ratepayers to the risk of nonperformance if the QF went off-line or simply failed to perform. While termination penalties or the posting of security could mitigate some of the concern, calculating a CT cost based on an economic carrying charge rate and escalating for inflation would eliminate this concern. In addition, as pointed out by SCE and TURN, it would be inappropriate to use a 20-year levelized value for a contract of less than 20 years in length. Using an economic carrying charge rate, escalated for inflation over the life of the contract, allows us to provide more flexibility in contract terms, from one year up to five years with the same CT cost estimate. ~~As-available capacity prices should be expressed in real dollars.~~

For the as-available contract option, we adopt the CT cost and ~~real~~ economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B, with an ~~ancillary services adjustment and an~~ energy benefits adjustment subtracted from the adopted value. TURN calculates a total marginal CT cost of $64.13/kW-year in 2006. Using the adopted TURN value for $64.13, the resulting capacity value would be $47.35~~32.53~~/kW-year ($64.13/kW-year - ~~$14.82/kW-year -~~ $16.78/kW-year).

Page 100

The QF Parties recommend that the Commission should provide the following options to QFs with expiring contracts and new QFs: (1) A QF could choose to be paid

SRAC and as-available capacity payments (similar to the existing SO1 contracts); (2) if the QF is willing to enter into a PPA of at least 10 years but no more than 20 years, the QF should receive a PPA based on the all-in cost of a new combined cycle power plant, using updated assumptions and the Commission's MPR pricing model; and (3) negotiated agreements. ~~CAC/EPUC and~~ CCC also recommend that the Commission adopt, as a goal, a cogeneration portfolio standard. The cogeneration portfolio standard would require the utilities to continue to make available long-term standard offer

Page 118

First, for existing QFs, the utilities shall offer new one- to five-year, as-available standard offer contracts to QFs. The contracts shall be updated to require compliance with CAISO tariffs, including the Resource Adequacy (RA) tariff, to the extent those tariffs are applicable to the QF. However, QFs with expiring contracts seeking to sign new, one- to five-year as-available contract shall not be required to provide new credit support provisions nor new interconnection studies.

Page 118-119

QFs under the one- to five-year as-available contracts shall receive SRAC energy payments as discussed herein along with the as-available capacity payment described herein. As described above, once MRTU is fully operational, we anticipate further adjustments may be made to the MIF based energy payments. The energy prices paid under all one-to-five-year contracts entered into pursuant to this Decision will be adjusted on a going forward basis using the adjusted MIF. New contracts will be subject to any changes in capacity payments resulting from future modifications to the RA counting rules; existing contracts will not be affected. The utilities ~~QFs larger than one megawatt in dependable capacity~~ will be responsible for scheduling coordination with the CAISO. However, at the election of the QFs, the utilities must provide that service for a reasonable cost. We adopt PG&E's recommendation to use the EEI Master Contract as a starting point for new standard QF contracts, as described herein. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., greenhouse gas costs, regulatory compliance required capital additions, electric reliability organization (ERO) costs. For purposes of expeditious contract development and adoption, we direct that the form standard offer contract, attached to this decision as Appendix 1, be used as a starting point template for firm capacity long term contracts.

Second, the utilities will offer a one- to ten-year contract term to those QFs with expiring contracts that are willing to provide unit firm capacity and that desire a longer-term contract. As with the as-available contracts, QFs under the one- to ten-year fixed capacity contracts will receive energy payments based on the MIF, as discussed herein, with the energy prices paid under all one- to ten-year contracts adjusted on a going forward basis to reflect updates to the MIF. Long-term firm capacity payments will be based on the MPR model in Resolution E-4049 and using a 10 year contract term, less the value of savings gained from inframarginal rents, which results in a cost of $135.97/kW-year. The higher capacity payments associated with the firm capacity contracts will appropriately compensate the QFs for the increased hedge value of assuring firm capacity for a longer term. QFs with expiring contracts seeking to sign new, one- to ten-year contracts shall also not be required to provide new credit support provisions nor new interconnection studies. These contracts will only be available to those QFs willing to offer unit-firm capacity. The all-in payments associated with the two prospective QF Program options are shown in Table 4a, attached to this order, at an illustrative gas price. QFs may also elect an LRAC firm energy pricing option as discussed herein for the term of the contract.

Page 120

Third, we adopt a contract option for new "small" QFs ~~under 25 MW~~ as described by TURN and modified by EPUC/CAC. As stated by TURN and EPUC/CAC this option is necessary because such a ~~small~~ QF is unable to bid in a utility RFO, generally does not have the resources or expertise required to negotiate and enter into a bilateral contract with a utility, and is prohibited by current rules from selling surplus generation directly to the CAISO. This option will further the goal of EAP II to encourage the development of new DG.

Therefore, all new QFs shall obtain a standard contract under the Prospective QF Program under the following conditions, (1) the project is either 25 MW or less, or ~~stated as~~ offering energy deliveries with an annual GWh limitation of 164,250 MWh (25 MW x 8760 x 0.75) or less, (2) consume at least 25% of their power internally and (3) sell all surplus power to the utility. These new QFs shall interconnect to the utility under Rule 21.

The new standard contracts will also have updated performance requirements to reflect the firm capacity, but QFs with expiring contracts seeking to sign new unit-firm contracts shall not have to provide additional credit support, nor should they be required to perform additional interconnection studies. The utilities will continue to be ~~QFs larger than one megawatt are~~ responsible for scheduling coordination, although the QF has the option to act as its own scheduling coordinator. To the extent the utility does not act as a scheduling coordinator, it ~~utilities~~ must offer scheduling service to QFs at a reasonable cost. QFs who are not able to offer unit firm capacity will be able to either continue on a one- to five-year as-available contract from year to year or may participate in utility resource solicitations and bilateral negotiations.

Page 121

solicitations can best reflect the utility's long-run avoided cost for the specific type of product needed and provided. As we stated in D.96-10-036, "[N]o preference for QF power justifies payment above levels arrived at by all source bidding, as such above market prices would violate PURPA's standard of ratepayer indifference." We uphold the same principle today. Contrary to the QF representatives claims, we are under no PURPA obligation to require long-term standard offers, and we find no mandated minimum term for PURPA required purchases. Looking to FERC regulations, we similarly find no mandated minimum term. We do not want to see erosion of the utilities' QF supplies, therefore we expect that as old QF contracts expire, new or renewed QF contracts will replace them. All QF resources acquired under the prospective QF program constitute per se ratepayer benefits. Also, increases in QF contractual capacity that are consistent with increases permitted by Public Utilities Code § 371 will be accommodated by the standard contracts in the prospective QF program.

Page 121

In addition to the contract option available to new small QFs described above, all ~~If a~~ new QFs may have ~~seeks~~ access to the contract options set forth herein just as existing QFs have, consistent with the need determination in the ~~IOU must determine if it would be inconsistent with the existing need determination from the~~ Long-Term Procurement Plan (LTPP) proceeding. ~~Further, the utility must consult with its Procurement Review Group (PRG) within 20 days of receiving a contract request from a QF. The PRG consultation period shall be initiated within 20 days of receiving a contract offer from a QF.~~ If a QF believes that a contract is being unreasonably withheld, it may file a complaint with the Commission. Utilities and QFs will also have the opportunity to address the need for new contracts as part of the utilities' long-term procurement plan filings in R.06-02-013 or its successor.

Page 123

Furthermore, requiring the utilities to make available one to ten-year unit firm capacity contracts, as well as optional one- to five-year as-available contracts is consistent with and supports one of the key actions in the EAP II. ~~Our prospective QF Program process will ensure that the amount of QF power under contract is consistent with the utilities' need. If a utility currently does not need additional QF power, for example, the utility is only required to renew existing contracts if it chooses, and will not be required to purchase new QF capacity if the utility can demonstrate that it no longer needs capacity.~~

Pages 132-133

We find that QFs should generally be required to comply with applicable CAISO tariff requirements, however, as recommended by the CAISO and SDG&E, we do not expect existing QFs to be required to complete new interconnection studies. As observed by several parties, neither the CAISO nor the utilities have described what type of disruption would be caused by retaining QFs' existing arrangements, and in fact, CCC points out that the Kern River Cogeneration Company (KRCC) contract would extend KRCC's existing interconnection agreements for the term of that contract, five years. The current

"CAISO exempt" and "must-take" status of the QF contracts stems from the fact that the CAISO did not exist when the contracts were signed. New contracts must explicitly take the existence of the CAISO and its tariff requirements into account. We reject ~~adopt~~ PG&E's recommendation that QFs one MW or greater should be required to comply with the CAISO tariffs. We also reject ~~adopt~~ PG&E's recommendation that QFs serve as their own scheduling coordinators. The CAISO must accept QF power as a "must-take" resource and QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations. Moreover, the utility should continue to serve as the scheduling coordinator for QFs, however, the QF should have the option of serving as its own scheduling coordinator. The QF has the ~~, with the~~ option of purchasing these services from the utility at cost.

Page 136-137

In comments, various parties point out that the decision does not sufficiently address all technical issues necessary to ensure smooth implementation of the QF program. We agree and shall direct the Energy Division to coordinate a technical workshop within ~~60~~ 10 business days of the effective date of this decision. As recommended by TURN, parties shall create a list of the relevant issues and recommend proposals for resolving them for discussion at the workshop. ~~Further, the respondent IOUs shall present at this workshop their draft standard offer contracts.~~ The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

PROPOSED MODIFICATIONS TO
FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact

~~8. It is neither reasonable nor practical to base short-run avoided costs on a "QF-out" or "aggregate value" pricing methodology because the continuing long-term obligations to thousands of megawatts of QF power mean that QF power cannot be "out".~~

~~12. Given the amount of QF generation currently under contract to the IOUs, an energy price that is based on an assumption that a large block of that generation has disappeared is not reasonable.~~

33. NP15/SP15 day-ahead contracts are ~~significantly~~ firmer than QF as-available power contracts which have no penalties for non-delivery, no forecasting requirements, no performance requirements, and a unilateral right to terminate on 30-days notice.

34. Using a levelized nominal dollar value to compute the CT cost would ~~overstate the avoided capacity cost as well as~~ present additional cost and risk for utilities and ratepayers.

36. For purposes of calculating payments for as-available capacity, it is reasonable to adopt the full CT cost and ~~real~~ economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B, with ~~an ancillary services adjustment and~~ an energy benefit adjustment subtracted from the adopted value as suggested by SDG&E and TURN.

38. A simplified version of the Edison Electric Institute Master Agreement will be the basis for our prospective QF Program contract options. The simplified version should contain, at a minimum, the contract features presented in Table 1 of this decision. For purposes of expeditious contract development we direct that the form standard offer contract attached to this decision as Appendix 1, shall be used as a starting point template for QFs seeking firm capacity long term contracts.

41. It is reasonable to allow new QFs under 25 MW or offering the annual energy delivery equivalent, not to exceed164,250 MWh, that consume at least 25% of the power internally and sell 100% surplus to the utility to obtain an as-available standard contract.

46. A technical workshop should be held within ~~60~~ 10 business days after the effective date of this decision to address issues associated with the implementation of the QF program.

47. FERC Order 688 recognizes that Section 210(m)(6) of PURPA protects the rights and remedies under a contract or obligation in effect or pending approval before a state regulatory authority.

48. In FERC Order 688, FERC interpreted the term "obligation" as a "legally enforceable obligation," which is established through a state's implementation of PURPA.

49. The Commission initiated these consolidated proceedings in response to requests from the QF community for Commission assistance in development of a long term policy for expiring QFs, the availability of contractual options for those QFs, and pricing under those contracts.

50. The Commission initiated these consolidated proceedings in April of 2004, prior to the date of enactment of section 210(m) (i.e., August 8, 2005).

51. It is reasonable that our Prospective QF Program should accommodate increases in contractual capacity to the extent that such increases are consistent with Section 371 of the Public Utilities Code.

Conclusions of Law

~~3. No right, contract term, or fair market expectation exists that the Commission must adopt the QF-in/QF-out approach to developing short-run avoided costs.~~

~~5.~~ The Commission should assure ~~adjust the factors in the Transition Formula such~~ that the SRAC energy prices ~~resulting from the formula continue to~~ accurately reflect the utilities' avoided costs.

~~13. Failure to consider utility resource needs in our long-term QF policy options would prevent us from achieving our goal of environmentally-sensitive, least-cost electric service.~~

~~14.~~ IOUs should modify their monthly SRAC energy prices using the MIF adopted in this order. No pricing determinations under this decision shall go into effect until the Commission has approved the Prospective QF Program's standard offer contracts and those contracts are available to QFs.

~~17.~~ A solicitation process wherein the IOUs would issue requests for offers from QF generators to meet specific, identified resource needs, ~~is~~ may be insufficient to meet the must purchase obligations in PURPA.

20. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., greenhouse gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs).

21. The CAISO must accept QF power as a must-take resource; QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations.

22. The utility should continue to serve as the scheduling coordinator for QFs, however, the QF should have the option of serving as its own scheduling coordinator. In such a case, the QF has the option of purchasing these services from the utility at cost.

23. It is the state regulatory authority that determines whether and when a legally enforceable obligation is created, and the procedures for obtaining approval of such an obligation under Section 210(m) of PURPA.

24. These proceedings will result in a contract or legally enforceable obligation with an electric utility as of the date of the Commission's final decision in these consolidated proceedings.

25. The prospective QF program should include an LRAC firm pricing option that reflects the adopted value for firm capacity of $136/kW-year, a fixed heat rate of 8,100 Btu/kWh and the adopted, escalating O&M adder for the term of the contract.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall revise their short-run avoided cost (SRAC) calculations in conformance with the discussion, findings, and conclusions set forth in this decision as summarized in Table 1. The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

2. Energy Division shall hold a technical workshop within ~~6~~10 business days of the effective date of this decision. Parties shall create a list of the relevant issues and recommend proposals for resolving them for discussion at the workshop. Further, the respondent Investor-Owned Utilities (IOUs) shall present at this workshop their draft standard offer contracts. For purposes of expeditious contract development we direct that the form standard offer contract attached to this decision as Appendix 1, shall be used as a starting point template for firm capacity long term contracts.

3. The implementation Energy Division workshop is to be strictly monitored process with the Assigned Commissioner presiding over issues identified and left unresolved by the final decision.

4. The Assigned Commissioner's Ruling on any outstanding implementation or standard offer contract issues shall be issued no later than 21 days after the conclusion of the Energy Division workshop.

Table 1
Qualifying Facility (QF) Programs
Adopted and Existing

No.	Provision	PROSPECTIVE QF PROGRAM (Adopted) (For Any Future Contract for Expiring and Expired QFs; and for New QFs As Described)		EXISTING QF PROGRAM (Will Phase Out With QF Contract Expiration)	
		One- to Five-Year As-Available Energy Contract			
2a	Calculation of Capacity Price Based on the fixed cost of a Combustion Turbine (CT) as proposed by TURN; ~~less the estimated value of Ancillary Services (A/S) as proposed by SDG&E; and~~ less the capacity value that is recovered in energy market prices as proposed by TURN and SDG&E.				

Table 4a
All-In Power Prices
Adopted Energy and Capacity Pricing
at an Illustrative Gas Price

	QF Contract Option	Illustrative Gas Price Burnertip $/MMBtu	Heat Rate (IER) Btu/kWh	O&M Adder $/MWh	Capacity Price $/kW-year	All-In Power Price $/MWh	All-In Effective Heat Rate Btu/kWh
	A	B	C	C	E	F= B x C + D + (E/8760)*1000	G = F ÷ B
Adopted	As-Available Power	7.50	8,598	2.65	~~$35.53~~ $47.35	~~$71~~ $73	~~9,672~~ 9,446

Attachment

Master Power
Purchase & Sale
Agreement
(Firm, Unit-Contingent Power)

California Public Utilities Commission

MASTER POWER PURCHASE AND SALE AGREEMENT
(FIRM, UNIT-CONTINGENT POWER)

COVER SHEET

This *Master Power Purchase and Sale Agreement* ("*Master Agreement*") is made as of the following date: _________________ ("Execution Date"). The *Master Agreement*, together with the exhibits, schedules and any written supplements hereto shall be referred to as the "Agreement." The Parties to this *Master Agreement* are the following:

Name ("__________________" or "Buyer")

All Notices:

Street: ______________________________________

City: _________________________Zip: ___________

Attn: Contract Administration
Phone: ______________________________________
Facsimile: ___________________________________
Duns: _______________________________________
Federal Tax ID Number: _______________________

Invoices:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Scheduling:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Payments:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Wire Transfer:
BNK: _____________________________________
ABA: _____________________________________
ACCT: ____________________________________

Credit and Collections:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Name ("_______________" or "Seller")

All Notices:

Street: ______________________________________

City: ______________________Zip: ____________

Attn: Contract Administration
Phone: ______________________________________
Facsimile: ___________________________________
Duns: _______________________________________
Federal Tax ID Number: _______________________

Invoices:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Scheduling:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Payments:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

Wire Transfer:
BNK: _____________________________________
ABA: _____________________________________
ACCT: ____________________________________

Credit and Collections:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: _____________________________________
Phone: ____________________________________
Facsimile: _________________________________

IN WITNESS WHEREOF, the Parties have caused this Master Agreement to be duly executed as of the date first above written.

Buyer Name	Seller Name
By: ________________________________	By: ________________________________
Name: ______________________________	Name: ______________________________
Title: _______________________________	Title: _______________________________

GENERAL TERMS AND CONDITIONSError! Bookmark not defined.
GENERAL DEFINITIONS

"Accepted Electrical Practices" means those practices, methods, applicable codes and acts engaged in or approved by a significant portion of the electric power industry during the relevant time period, or any of the practices, methods and acts which, in exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at reasonable cost consistent with good business practices, reliability, safety and expedition. Accepted Electrical Practices are not intended to be limited to the optimum practices, methods or acts to the exclusion of others, but rather to those practices, methods and acts generally accepted or approved by a significant portion of the electric power industry in the relevant region, during the relevant time period, as described in the immediately preceding sentence.

"Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

"Availability Notice" shall have the meaning set forth in Section 3.5 hereof.

"Agreement" has the meaning set forth in the Cover Sheet.

"Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

"Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

"Buyer" means the Party to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

"CAISO" means the California Independent System Operator Corporation

"Claiming Party" has the meaning set forth in Section 3.3.

"Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

"Cogeneration Facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

"Contract Capacity" means the amount of Generating Facility capacity, in kW, designated by Seller and sold to Buyer pursuant to this Agreement.

"Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

"Day" means a period of twenty-four (24) consecutive hours (as shortened of lengthened for daylight savings time), beginning with the hours ending 01:00 prevailing local time for the Generating Facility.

"Defaulting Party" has the meaning set forth in Section 5.1.

"Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction.

"Delivery Point" means the point at which the Product will be delivered and received, as specified in the Transaction. For Sellers electing Option I in Section 2.3, the Delivery Point is a point on the high-voltage side of the generator step-up transformer which has a measured output net of Station Use. For Sellers electing Option II in Section 2.3, the Delivery Point is a point where the electrical conductors of the Seller contact the electrical conductors of the Buyer.

"Early Termination Date" has the meaning set forth in Section 5.3.

"Effective Date" means the date specified in Section 2.6 which is the date that Seller begins deliveries and Buyer begins receiving and paying for Contract Capacity and Net Electrical Output pursuant to this Agreement.

"Energy" means electrical energy expressed in MWh of the character commonly known as three (3) phase, sixty (60) hertz electric energy delivered at an acceptable voltage consistent with Accepted Electrical Practices and the requirements of the CAISO.

"Environmental Costs" means all costs incurred by Seller after September 30, 2007 associated with obtaining and/or maintaining environmental permits and complying with environmental laws and regulations with respect to the construction and operation of the Facility, including but not limited to, any permit fees or costs associated with air emissions, hazardous waste, water usage, wastewater discharge, variable emission fees and costs of emission trading credits (such as RECLAIM). Environmental Costs shall include, but not be limited to, a tax, imposition or obligation based directly or indirectly on greenhouse gas emissions.

"Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

"Event of Default" has the meaning set forth in Section 5.1.

"Execution Date" means the date this Agreement is signed by the Parties as set forth on the Cover Sheet.

"FERC" means the Federal Energy Regulatory Commission or any successor government agency.

"Final Schedule" means the final hourly schedule of the amounts of Net Electrical Output that the Facility is expected to be available to produce each hour of a Day based upon the applicable Weather Forecast and mechanical conditions at the Facility.

"Fuel" means the Generating Facility's source of combustion including, but not limited to, natural gas, refinery gas, or forms of petroleum refining by-products.

"Fixed Capacity Payment" means the payment made to Seller by Buyer on a monthly basis, for the Contract Capacity made available to Buyer during the Term of this Agreement.

"Generating Facility or Facility" means all of Seller's generating units, together with all protective and other associated equipment and improvements owned, maintained, and operated by Seller, which are necessary to produce electrical power, excluding associated land, land rights, and interests in land.

"Generation Meter Multiplier" means a number which when multiplied by a Generating Facility's metered quantity will give the total demand to be served from that Generating Facility.

"Interconnection Facilities" is defined as all means required, and apparatus installed, to interconnect and deliver power from the Generating Facility to the Buyer's system in accordance with applicable regulatory authority directives, including, but not limited to, connection, transformation, switching, metering, communications, control, and safety equipment, such as equipment required to protect (a) the Buyer's system and its customers from faults occurring at the Generating Facility, and (b) the Generating Facility from faults occurring on the Buyer's system or on the systems of others to which the Buyer's system is directly or indirectly connected.

"Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

"Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

"Master Agreement" has the meaning set forth on the Cover Sheet.

"NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Council or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

"Net Electrical Output" means the net Energy delivered by Seller from the Facility to Buyer at the Delivery Point pursuant to this Agreement, but prior to any generation meter multiplier reduction applied by the CAISO. For purposes of this Agreement, Net Electrical Output shall also include any associated ancillary services capable of being provided by the Facility.

"Net of Station Use" means capacity and/or energy produced by the Generating Facility less Station Use.

"Non-Defaulting Party" has the meaning set forth in Section 5.2.

"Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

"Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to an attached exhibit hereto or as otherwise specified by the Parties in the Transaction.

"QFID Number" means a Buyer designation for purposes of identification specific to a qualifying facility.

"Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

"Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

"Scheduled Outage" means a period during which all or a portion of a Generating Facility's capacity is not available for operation due to planned maintenance that has been scheduled in advance in accordance with Section 4.03 hereof.

"Scheduling Coordinator" means the entity, who shall be responsible for performing the responsibilities defined for a Scheduling Coordinator in the CAISO tariff, including but not limited to scheduling and settlements of test energy and the Net Electrical Output from the Facility with the CAISO.

"Seller" means the Party to a Transaction that is obligated to sell and deliver the Product, as specified in the Transaction.

"Small Power Production Facility" means a facility which (1) meets the maximum size criteria specified in Section 292.204(a); (2) meets the fuel use criteria specified in Section 292.204(b); and (3) meets the ownership criteria specified in Section 292.206.

"Standard Site Conditions" means the following conditions, as may be modified from time to time, as mutually agreed to by Seller and Buyer:

Ambient Temperature	__ degrees Fahrenheit
Relative Humidity	__ percent
Barometric Pressure	_____ psia
Generator Power Factor	__

"Station Use" means energy used to operate the Generating Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

"Summer Availability Incentive" means an amount [To be determined in Workshop].

"Summer Availability Payment" shall mean the incentive bonus or penalty payable by Buyer or Seller with respect to the summer availability for the immediately proceeding Summer Period as calculated in accordance with Schedule 3.01 hereof.

"Summer Period" means [To be a Buyer specific "on-peak/peak hours" only determination]

"Term" shall have the meaning set forth in Section 2.7 hereof.

"Termination Payment" has the meaning set forth in Section 5.2.

"Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Master Agreement.

"Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

"Unit-Contingent" means that the delivery and supply of capacity and energy to Buyer from Seller is contingent on Seller's Generating Facility operating and Seller has no other obligation to Buyer to replace or compensate Buyer in the event the Generating Facility output is reduced.

"Unscheduled Outage" means a period during which one or more Units are not available for operation due to the need to maintain or repair a component of the Facility that has not been scheduled in advance.

"Variable Operation and Maintenance Adder" shall have the meaning set forth in Schedule 3.02 hereof.

"Weather Forecast" means the ambient temperature, humidity, and barometric pressure forecasted by Seller, at the time an Availability Notice is prepared, to prevail at the times covered by the relevant Availability Notice. The hourly humidity forecast applied in any Availability Notice will be based on historical seasonal averages, unless conditions are forecasted to diverge significantly from such seasonal averages. The barometric pressure applied to any Availability Notice will be XX.XX psia. [To be determined in Workshops].

"Winter Availability Incentive" means an amount [To be determined in Workshops].

"Winter Availability Payment" shall mean the incentive bonus or penalty payable by Buyer or Seller with respect to the winter availability for the immediately proceeding Winter Period as calculated in accordance with Schedule 3.01 hereof.

"Winter Period" means [To be a Buyer specific "partial-peak/mid-peak hours" only determination]

TERMS AND TERMINATION

2.1 Seller's Generating Facility:

QFID Number: XXXX

Contract Capacity: _ kW. (Net of Station Use)

Location: Project Name

Street

City, Ca. Zip

Type: (Check One)

Cogeneration Facility.

______________ (primary energy source)

Small Power Production Facility.

______________ (primary energy source)

2.2 Expected annual energy deliveries: ________________ kWh.

2.3 Operating Options pursuant to Article One: (Check One)

________Operating Option I (Buy/Sell): Entire Generating Facility output less Station Use sold to Buyer.

________Operating Option II (Surplus Sale): The Net Electrical Output, Generating Facility output less Station Use and any other use by Seller, sold to Buyer.

2.4 Metering Location: (Check one)

Seller selects metering location pursuant to Section 10.2 as follows:

High-voltage side of the Interconnection Facilities transformer.

Low-voltage side of the Interconnection Facilities transformer with the transformer loss compensation factor determined in accordance with Section 10.2.

2.5 Notices

Any written notice, demand, or request required or authorized in connection with the Agreement shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified in the Cover Sheet.

Seller's notices to Buyer pursuant to this Section 2.5 shall refer to the QFID number set forth in Section 2.1(a).

The designated addresses may be changed at any time upon similar notice by the Party's authorized representative.

2.6 Effective Date. This Agreement shall become effective on the Effective Date.

2.7 Termination. Unless terminated earlier as provided herein, this Agreement shall terminate at 2400 hours on the date which is _[Buyer determined number of years not to exceed 10 years]_years from the Effective Date ("Term").

2.8 Governing Terms. Unless otherwise specifically agreed, the relationship between the Parties shall be governed by this Master Agreement. This Master Agreement (including all exhibits, schedules and any written supplements hereto), shall form a single integrated agreement between the Parties.

OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations. Seller shall sell and deliver to the Buyer at the Delivery Point, and the Buyer shall purchase and receive at the Delivery Point, the Contract Capacity and the Net Electrical Output. Other than CAISO charges or costs, Seller shall be responsible for any costs or charges imposed on or associated with the Contract Capacity and Net Electrical Output up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Contract Capacity and associated Net Electrical Output or its receipt at and from the Delivery Point, and any losses associated with the generation meter multiplier or other charges assessed by the CAISO on the Net Electrical Output.

3.2 Transmission and Scheduling. Seller shall be responsible for delivery of the Contract Capacity and Net Electrical Output to the Delivery Point. Buyer, at the option of Seller, shall be the Scheduling Coordinator for the Facility and shall be responsible for any costs or charges assessed by the CAISO in the Buyer's role as Scheduling Coordinator for the Facility and shall be responsible for any operations related charges applied by the CAISO, if any, between Seller and the CAISO. In its role as the Scheduling Coordinator, the Buyer shall also be responsible for reconciling and settling the charges and/or credits associated with the Net Electrical Output with the CAISO. Seller shall use commercially reasonable efforts to provide Buyer with such data as is necessary for the Buyer to carry out its responsibilities as Scheduling Coordinator. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule with the CAISO to receive the Net Electrical Output at the Delivery Point.

3.3 Imbalance Costs. The Buyer recognizes that its purchases of Net Electrical Output are on a unit-contingent basis, and the actual amounts of Net Electrical Output delivered in any hour depend on mechanical and climatic conditions prevailing at the Facility at the time of production, among other factors (including, but not limited to, an inability to deliver fuel to the Facility). Seller recognizes that CAISO may assess imbalance costs, penalties or sanctions when the Net Electrical Output deviates from the amounts of available Energy scheduled by the Buyer and pre-scheduled with CAISO. Seller agrees, within Accepted Practices, to cooperate with Buyer to minimize such imbalance costs, penalties or sanctions. The Buyer shall bear any imbalance costs, penalties and sanctions assessed by the CAISO.

3.4 Availability Schedule. Not later than ten (10) Business Days prior to the beginning of each month during the Term, Seller shall provide a non-binding hourly schedule of the estimated amounts of Net Electrical Output that the Facility will be available to produce for the upcoming month (each "Estimated Monthly Availability Schedule") . The estimated amounts of Net Electrical Output that the Facility will be available to produce contained in any Estimated Monthly Availability Schedules and Availability Notices shall be based upon typical ambient temperatures.

3.5 Availability Notice. Not later than two (2) days before each Day during the Term, Seller shall provide the Buyer a non-binding hourly schedule of the amounts of Net Electrical Output that the Facility is expected to be available to produce each hour of such Day (each an "Availability Notice") based upon the applicable Weather Forecast and mechanical conditions at the Facility. Availability Notices for Sundays and Mondays shall be provided on the preceding Thursday. Prior to the relevant day of delivery and at a time mutually agreed to by Buyer and Seller, Seller shall submit a Final Schedule to Seller.

3.6 Scheduled Outages. Not later than forty-five (45) Days prior to the commencement of any calendar year during the Term, Seller shall submit to Buyer its proposed Scheduled Outages for the upcoming year ("Outage Schedule"). Within ten (10) Days after its receipt of the Outage Schedule, the Buyer shall notify Seller in writing of any reasonable request for changes to the Outage Schedule. If the Buyer fails to provide such notice within the prescribed period, the Buyer shall be deemed to have approved the Outage Schedule. If the Buyer request changes to the Outage Schedule, Seller shall use commercially reasonable efforts to accommodate such requested changes within Accepted Electrical Practices and consistent with Seller's obligation to supply thermal energy to host. Buyer shall arrange and be responsible for coordination of Outage Schedules with CAISO. No Scheduled Outages shall be scheduled during the Summer Period except as may be directed by CAISO. Seller shall notify Buyer of an Unscheduled Outage or a change in a Scheduled Outage and the estimated time of return of reductions in Contract Capacity as soon as practicable after the condition becomes known to Seller.

3.7 Dispatch by CAISO. The Buyer recognizes that, pursuant to an order of the FERC (in Docket EL00-95-012 or otherwise), Seller may be required to offer for sale to CAISO in CAISO's real time market, or to any other entity having jurisdiction pursuant to an order of the FERC, any Energy from the Facility that is available and not already scheduled on a day-ahead basis by the Seller. In the event that CAISO or such other entity exercises any right it may have to require Seller to deviate from is Final Schedule Buyer pay for any Net Electrical Output in excess of the Final schedule in accordance with Schedule 3.02. In the event, Net Electrical Output is reduced for the Final Schedule Buyer will excuse Seller from all availability and performance-related requirements that are impacted by Seller's compliance with the provisions of this section.

3.8 Environmental Costs. All Environmental Costs incurred by Seller shall be paid by Buyer and included in the payments made to Seller within 30 day of the date incurred.

3.9 Payments for Contract Capacity and Net Electrical Output. Seller shall sell and deliver to Buyer at the Delivery Point, and the Buyer shall purchase and receive at the Delivery Point, the Contract Capacity and the Net Electrical Output. Payment for Contract Capacity shall be determined in accordance with Schedule 3.01 of this Agreement. Payment for Net Electrical Output shall be determined in accordance with Schedule 3.02.

3.10 Capacity Testing.

Seller shall provide the Buyer at least seven (7) Days' notice if Seller intends to conduct a capacity test. Any capacity test may be conducted during the course of regular operations or during a test conducted for the purpose. In the event that Seller elects to perform a capacity test during a period that the Seller has not otherwise elected to schedule the Facility, the Buyer shall take delivery of all capacity and energy delivered, for purposes of the capacity test, for at least six consecutive operating hours and shall schedule associated Net Electrical Output with the CAISO as required.

Capacity tests may begin only after the Facility has been successfully started and has been in stable steady-state operation for at least one (1) hour prior to the test period. During the capacity test, Seller shall operate the Facility in a manner that it is willing to operate on a sustained basis under prevailing conditions.

(c) Within ten (10) Days following any capacity test, Seller shall provide the Buyer with the results of such capacity test, including metering readings and copies of Facility log sheets verifying the operating conditions and Net Electrical Output of the Facility during the test, and a curve of the Net Electrical Output versus ambient temperature.

In the event that the Contract Capacity determined by any capacity test is reasonably unsatisfactory to Seller (in that Seller believes that the test result does not accurately represent the actual capacity of the Facility), Seller may schedule up to two (2) additional capacity tests within any calendar year.

In the event that the Contract Capacity determined by any capacity test is reasonably unsatisfactory to Buyer (in that Buyer believes that the test result does accurately represent the actual capacity of the Facility), Buyer may schedule up to two (2) additional capacity tests within any calendar year.

In the event of any additional capacity test conducted pursuant to Section 3.10(d) or 3.10(e), Seller shall have the opportunity prior to any such test to perform a water wash of the units comprising the Facility.

3.11 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under this Agreement (other than obligations to make payments) despite all reasonable efforts of such party to prevent or mitigate its effects, and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, during the continuance of the Force Majeure, the obligation of the Claiming Party to perform the obligations so affected shall be excused. The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to deliver all or part of the Net Electrical Output pursuant to this Agreement, and such failure is not excused under the terms of this Agreement, by Force Majeure, by Buyer's failure to perform or by any Scheduled Outage or Unscheduled Outage of the Facility, Buyer shall notify Seller of Seller's failure and Seller shall promptly take appropriate steps to remedy such failure. To the extent Seller fails to deliver all or part of the Net Electrical Output pursuant to this Agreement, Buyer's payment to Seller for the month in which the failure occurred shall reflect only the net Electrical Output delivered during that month.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Net Electrical Output pursuant to this Agreement, and such failure is not excused under the terms of this Agreement, by Force Majeure or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred. The amount that would have been due to Seller had Buyer received the Net Electrical Output as set forth in this Agreement.

EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for Buyer's failure to schedule and/or receive all or part of the Net Electrical Output, the exclusive remedy for which is provided in Article Four) if such failure is not remedied within three (3) Business Days after written notice;

such Party becomes Bankrupt;

such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;

5.2 Remedies.

(a) If an Event of Default occurs and shall be continuing, the party that is not the Defaulting Party (the "Non-Defaulting Party") shall have the right to suspend performance under this Agreement upon written notice to the Defaulting Party, such notice of suspension to be effective immediately upon receipt.

(b) If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the Non-Defaulting Party shall have the right to accelerate all amounts owing between the Parties so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate. As soon as practicable, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

(c) At any time prior to or after the receipt of such notice of suspension by the Defaulting Party, the Non-Defaulting Party may exercise any remedies available to it at law or in equity, including, but not limited to, the right to seek injunctive relief to prevent irreparable injury to the Non-Defaulting Party.

(d) This Agreement shall continue for the Term unless terminated earlier as follows:

(i) By mutual agreement of the parties hereto; or

(ii) By either party in the event of a continuing Force Majeure for a period of twelve (12) months.

5.3 Early Termination. In the event of an early termination of this Agreement as provided in Section 5.2, the party seeking termination shall provide written notice to the other party indicating a date on which the Agreement shall terminate (which date shall not be earlier than thirty (30) days prior to the effective date of such notice (the "Early Termination Date"). On the Early Termination Date, this Agreement shall terminate subject to any terms and conditions as may be agreed to by the parties.

BILLING AND PAYMENT

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties, the calendar month shall be the standard period for all payments under this Agreement (other than Termination Payments). As soon as practicable after the end of each month, Seller will render to Buyer an invoice for the payment obligations incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties, Buyer shall ensure that payments for amounts billed hereunder shall be paid so that such payments are received by Seller by the fifteenth (15th) day of each month or the tenth (10th) day after receipt of the applicable invoice, whichever is later. Payment shall be made at the location designated by Seller to which payment is due. Payment shall be considered received when Seller receives such payment from Buyer. If the due date falls on a non-Business Day, then the payment shall be due on the Business Day immediately preceding such due date. Amounts not paid on or before the due date shall be payable with interest accrued at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made.

LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

GOVERNMENTAL CHARGES

8.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master Agreement in accordance with the intent of the parties to minimize all taxes , so long as neither Party is materially adversely affected by such efforts.

MISCELLANEOUS

9.1 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, each Party represents and warrants to the other Party that:

it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

it has all regulatory authorizations necessary for it to legally perform its obligations under this Master Agreement;

the execution, delivery and performance of this Master Agreement have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

this Master Agreement, and each other document executed and delivered in accordance with this Master Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

there is not pending or, to its knowledge, threatened against it any legal proceedings that could materially adversely affect its ability to perform its obligations under this Master Agreement;

no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Master Agreement;

it is acting for its own account, has made its own independent decision to enter into this Master Agreement and as to whether this Master Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Master Agreement;

it has entered into this Master Agreement in connection with the conduct of its business and it has the capacity or ability to make or take delivery of the Net Electrical Output described in this Agreement;

9.2 Title and Risk of Loss. Title to and risk of loss related to the Net Electrical Output shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Net Electrical Output free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

9.3 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

9.4 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

9.5 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

9.6 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), constitute the entire agreement between the Parties relating to the subject matter. This Agreement shall be considered for all purposes as prepared through the joint efforts of the parties and shall not be construed against one party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as “Regulatory Event”) will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties. The term “including” when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. This Agreement shall be binding on each Party’s successors and permitted assigns.

9.7 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

9.8 Forward Contract. The Parties acknowledge and agree that all Transactions constitute “forward contracts” within the meaning of the United States Bankruptcy Code.

METERING

10.1 All meters and equipment used for the measurement of power for determining Buyer's payments to Seller pursuant to this Agreement shall be provided, owned, and maintained by Seller unless otherwise agreed by Parties.

10.2 All the meters and equipment used for measuring the power delivered to Buyer shall be located on the side of the Interconnection Facilities transformer as selected by Seller in Section 2.4. If Seller chooses to have meters placed on the low-voltage side of the Interconnection Facilities transformer, a transformer loss compensation factor will be applied. At Seller's sole expense, manufacturer's certified test reports of transformer losses, in accordance with current national standards, will be provided and used to determine a transformer loss compensation factor, unless another method for determination of transformer losses has been mutually agreed upon to determine the actual measured value of losses.

10.3 Seller shall provide, at Buyer’s option and expense, access to real-time telemetry data via appropriate telecommunications equipment.

10.4 Meters shall be sealed and the seals shall be broken only when the meters are to be inspected, tested, or adjusted. Parties shall be given reasonable notice of testing and shall have the right to have a representative present on such occasions.

10.5 Meters shall be inspected and tested upon their installation and annually thereafter. At the requesting Party’s expense, a meter may be inspected or tested more frequently.

10.6 Metering equipment determined to be inaccurate or defective shall be repaired, adjusted, or replaced by owner such that the metering accuracy of said equipment shall be within two (2) percent. If a meter fails to register or if the measurement made by a meter during a test varies by more than two (2) percent from the metering standard used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for (a) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (b) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six (6) months.

Schedule 3.01

Contract Capacity Payment Provisions

A. Buyer shall make payment for Contract Capacity to Seller monthly. The payment for Contract Capacity shall consist of the sum of the monthly Fixed Capacity Payment and the seasonal Availability Payment.

The monthly Fixed Capacity Payment = ($136 x Contract Capacity) ÷ 12

B. Within fifteen (15) days following the end of each Summer Period during the Term, Seller shall provide the Buyer with a statement setting forth the Summer Availability achieved by the Facility during the immediately preceding Summer Period, calculated according to the formula set forth in Paragraph C. The statement shall also provide a calculation of the Summer Availability Payment payable by Buyer or Seller, as the case may be, based on the Summer Availability achieved by the Facility during the immediately preceding Summer Period. The Summer Availability Payment shall be calculated according to the following formula:

Summer Availability Payment =
Summer Availability Incentive x (Achieved Summer AF – Contract Summer AF) x 100

Achieved Summer AF = Summer Availability as calculated in Paragraph C of this Schedule 3.01; provided that the Achieved AF shall not be less than 92%.

Contract Summer AF = 95%.

Adjustments Based on Actual Winter Availability. Within fifteen (15) days following the end of each calendar year during the Term, Seller shall provide the Buyer with a statement setting forth the Winter Availability achieved by the Facility during the immediately preceding Winter Period, calculated according to the formula set forth below and in Paragraph C. The statement shall also provide a calculation of the Winter Availability Payment payable by Buyer or Seller, as the case may be, based on the Winter Availability achieved by the Facility during the immediately preceding Winter Period. The Winter Availability Payment shall be calculated according to the following formula:

Winter Availability Payment =
Winter Availability Incentive x (Achieved Winter AF – Contract Winter AF) x 100

Achieved Winter AF = Winter Availability as calculated in Paragraph C of this Schedule 3.01; provided that the Achieved AF shall not be less than the applicable Contract Availability for the Winter Period less eight percentage points.

Contract Winter AF = 90%; provided that during any Winter Period in which: (a) a Hot Gas Path Inspection occurs the Contract Winter AF shall equal 85% or (b) a Major Inspection occurs the Contract Winter AF shall equal 79%.

C. Calculation of Availability During Summer Period and Winter Period. Availability during a given Summer Period ("Summer Availability") or during a given Winter Period ("Winter Availability") shall be calculated according to the following formula (but in no event shall Availability during any period exceed 100%, notwithstanding anything to the contrary herein):

Availability during relevant period (i.e., Summer Period or Winter Period) = SHA / BPH

Where:

BPH = the number of hours in the relevant Summer Period or Winter Period, minus the number of Excused Hours during such Summer Period or Winter Period.

And SHA = the sum of the Hourly Availabilities determined for each hour in the relevant Summer Period or Winter Period, where each Hourly Availability is determined in accordance with the following formula:

Hourly Availability = [HN – (HS –HD)] / HC

Where:

HN = the hourly amount of Net Electrical Output that Seller informs Buyer will be available pursuant to its Availability Notice.

And HS = the hourly amount of Net Electrical Output scheduled by the Seller to be delivered to Buyer pursuant to Seller's Final Schedule.

And HD = the total Net Electrical Output actually delivered in the hour, adjusted to the ambient conditions set forth in the Weather Forecast for such hour.

And HC = the hourly amount of Net Electrical Output that would have been available if the Facility was run at Contract Capacity, adjusted to the ambient conditions set forth in the Weather Forecast for such hour.

The Parties hereto acknowledge that the difference between HS and HD shall equal zero, for purposes of the formula set forth above, for any hour that the amount of hourly Net Electrical Output delivered by Seller is greater than the amount of Net Electrical Output scheduled by Seller to be delivered in that hour.

Schedule 3.02

Contract Energy Payment Provisions

A. Buyer shall make payment for Net Electrical Output to Seller monthly. The monthly energy payment for Net Electrical Output shall, at the option of the Seller, be calculated in the following manner:

Monthly Energy Payment = Σ Monthly TOU Energy Payment$_i$

Monthly TOU Energy Payment$_i$ = [(GP x HR + O&M) x TOU$_i$] x Net Electrical Output$_i$

Where:

a. GP is the monthly natural gas price determined pursuant to paragraph B of this Schedule
b. HR is the monthly heat rate determined pursuant to paragraph C of this Schedule
c. O&M is the Variable Operation and Maintenance Adder determined pursuant to paragraph D of this Schedule
d. TOU is the Time of Use allocation factor determined pursuant to paragraph E of this Schedule
e. “i” is the seasonal TOU period

B. Details to be determined in workshops

C. Details to be determined in workshops

D. O&M equals $2.65/MWh in 2007 dollars with annual escalation details to be determined in workshops

E. TOU allocation Factor shall be determined in the following manner:

TOU Determination	
Summer On-Peak	1.4251
Summer Mid-Peak = [Total # hrs in month - (1.4251 * # Summer On-Peak hrs in month) - (0.8526 * # Summer Off-Peak hrs in month)] / # Summer Mid-Peak hrs in month	Calculated per Formula
Summer Off-Peak	0.8526
Winter Mid-Peak	1.2185
Winter Off-Peak = [Total # hrs in month – (1.2185 * # Winter Mid-Peak hrs in month) – (0.7760 * # Winter Super Off-Peak hrs in month)] / # Winter Off-Peak hrs in month	Calculated per Formula
Winter Super Off-Peak	0.7760

[Illustrative definitions which may vary by individual Buyer]

SEASON AND TIME PERIOD DEFINITIONS		
Time Period	Summer	Winter
	June 1 - September 30	October 1 - May 31
On-Peak	Noon - 6:00 p.m.	n/a
Mid-Peak	8:00 a.m. - Noon 6:00 p.m. – 11:00 p.m.	8:00 a.m. 9:00 p.m.
Off-Peak	11:00 p.m. - 8:00 a.m. Midnight - Midnight	6:00 a.m. - 8:00 a.m. 9:00 p.m. - Midnight 6:00 a.m. - Midnight
Super Off-Peak	n/a	Midnight - 6:00 a.m.

2007 Holidays: New Year's Day (1/1), Presidents' Day (2/19), Memorial Day (5/28), Independence Day (7/4), Labor Day (9/3), Veterans Day (11/11), Thanksgiving Day (11/22) and Christmas Day (12/25). When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

CERTIFICATE OF SERVICE

I, Kari Harteloo, certify that I have caused the *OPENING COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE ALTERNATE DECISION OF COMMISSIONER GRUENEICH* to be served by electronic mail on the parties listed below in accordance with the Commission's rules.

Dated September 10, 2007 at Portland, Oregon.

Kari Harteloo

Kari Harteloo

CALIFORNIA PUBLIC UTILITIES COMMISSION

Proceeding: R0404025
List Name: LISTQFISSUES
Last changed: August 30, 2007
and
Proceeding: R0404003
List Name: LISTQFISSUES
Last changed: August 30, 2007

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